TESTIMONY OF
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SENIOR VICE PRESIDENT
POWER ENGINEERS, INC.

Subject:
Transmission System Planning Process Overview
Development and Application of Transmission System Planning Criteria
Review of HECO Transmission Planning Criteria

INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Randall Pollock. I am employed by Power Engineers, Inc. and my business address is 3940 Glenbrook Drive, Hailey, Idaho 83333.

Q. What is your profession?

A. I am a Professional Engineer.

Q. What is your title or position?

A. My position at Power Engineers is Chairman of the Board, Senior Vice President, and Senior Project Manager. My professional title is Professional Engineer.

Q. Could you briefly describe your duties and responsibilities at Power Engineers?

A. At Power Engineers, I have two roles. My primary role is to function as a Senior Project Manager for our larger and more complex electrical utility projects, working to assist key clients with their projects. For example, I am currently working with a client in Texas for whom Power Engineers is providing a wide array of engineering services for approximately 100 projects per year including overhead and underground transmission line design, substation design, cost estimating, material procurement, construction management, and general consulting services.

My other role at Power Engineers is as Chairman of the Board of Directors. Power Engineers is an employee-owned company, and as one of the larger shareholders, I lead and participate in Power Engineers' Board of Director meetings and share in policy-making decisions with the other Directors. In the 22 years that I have been with Power Engineers, the company has grown from a small regional firm with about 20 employees to a larger international firm with approximately 600 employees and offices throughout the U.S., and in Europe and South America.

Q. How long have you been a professional engineer by profession?

A. Since 1972 as a degreed electrical engineer and since 1977, formally as a Professional Engineer. In 1977, I took the professional engineering exam for the State of Oregon, passed the exam, and became certified as a Professional Engineer.

Q. Are you a member of any professional organizations or associations?

A. Yes.

Q. Could you please summarize them?

A. I am a member of the National Society of Professional Engineers, the Idaho Society of Professional Engineers, and the IEEE (Institute of Electrical and Electronic Engineers)

Q. Could you briefly describe your work experience?

A. I received a Bachelors Degree in Electrical and Electronics Engineering from California State Polytechnic University (Cal Poly – Pomona) in 1972, with an emphasis in electrical power systems. At that time I began my engineering career with Pacific Power and Light Company, an electric utility company based in Portland, Oregon. I worked for Pacific Power until 1981, and during that time period I served the company in a number of capacities and geographical locations. From 1972 - 1976, I was based in Medford, Oregon and as an Assistant Area Engineer, was responsible for conducting detailed engineering planning and relay coordination studies for Pacific's electrical distribution system. In addition, I provided engineering expertise for the operation and maintenance of the system to the Operations Division during electrical system problems and on a day-to-day basis. I was also responsible for preparing cost estimates and budgets for capital projects and providing written justification for those projects to Pacific's corporate engineering and operations management. From 1976 - 1978 I worked in the corporate offices in Portland in the Engineering Standards group. In that role I wrote engineering standards for a variety of applications, including conductor installation and sag and tension guides, transformer loading, distribution feeder loading guides, and lightning performance, to name a few. From 1978-1981 I was the Area Engineer in Pacific's Casper, Wyoming office. In that role I had the responsibility for the engineering for all of the distribution systems in Central Wyoming. These responsibilities included planning studies and load forecasting, cost estimating, troubleshooting during outages, and providing engineering guidance to the Operations Division for evaluating system operation and maintenance issues. I also provided engineering for new and system upgrade projects and the technical interface for large industrial and commercial customers.

In 1981 I left the employ of Pacific Power and joined Power Engineers in Hailey, Idaho. During the last 22 years I have consulted with various clients on a wide variety of electrical utility transmission, substation, and distribution engineering projects. My work with Power Engineers has centered on specific projects related to the high voltage transmission system. I have completed projects for various companies that required environmental and engineering services for high voltage electrical systems up to 500kV. Over the years I have been responsible for completing electrical system planning studies, detailed design for transmission lines and substations, cost estimates and cash flows, material procurement, construction management, project engineering, and project management. I have also been responsible for providing engineering and management services for a number of transmission line routing projects to prepare environmental documentation to affect the permitting of transmission lines. For some of these projects I have provided expert witness services to support the project permitting process.

Q. Is HECO-300 a copy of your resume/curriculum vitae?

A. Yes, it is.

Q. What is the scope of your testimony?

A. My testimony will address:

1) System Planning Process Overview,

2) Development and Application of System Planning Criteria, and

3) Review of HECO's Planning Criteria as applied to the current project.

SYSTEM PLANNING PROCESS OVERVIEW

Q. What issues should be considered when conducting system planning studies?

A. The planning process for electric utility systems is conducted with consideration of a number of system, operational, and financial issues:

1) Decisions must be made well in advance of the projected need date because permitting and construction of facilities and/or implementation of programs can take many years.

2) Decisions are long-term. Utility infrastructure will, with regular maintenance and component replacement, remain in service indefinitely, for all practical purposes.

3) Because planning decisions contemplate the installation of facilities such as substations, generation plants, and transmission lines that have a very long life, consideration must be given to the future electrical system as a whole, in addition to the solution of the most immediate problems.

4) The analysis must be forward looking, with load forecasts based on the information available at the time of the study.

5) The system analysis is based on the measured and projected electrical load at each substation and existing/planned generation additions.

6) To facilitate financial and operational planning, the study recommendations that result based on specific load levels are translated to dates (year of need) based on the load forecast.

7) The technical analysis is conducted based on previously approved planning criteria, applied with judgment, to arrive at recommendations.

8) Recommendations that result from the study must balance system performance, including reliability, against cost.

9) The study process is an ongoing activity to take into account the changes over time to the forecasted load levels in any given year. Thus planning studies must be performed on a regular basis to keep up with changes.

Q. What types of data are needed to conduct planning studies?

A. Planning studies are necessarily forward looking. Forward-looking planning studies are based on information relevant at the time of the preparation of the study. Historical information and information from previous studies may be used to the extent it is useful in making and evaluating forward-looking projections. Load forecasts based on known development plans, economic factors, and historical load growth are needed. Detailed data on the historical and forecasted loads on individual substations and transmission and distribution lines are needed in order to construct a system model. With this data, a system model is constructed to serve as a tool to analyze the system.

Q. What tools are used by planning engineers to conduct system planning studies?

A. The primary analytical tool for modeling system performance is load flow analysis. Load flow analysis is performed with the aid of computers and determines the flow of electricity (loading) through lines and transformers along with voltages on the system. Load flows are performed with all lines, substations, and generators in-service.... the ideal situation. The analysis must also determine how the system will perform when stressed. For example, when one or more of the lines, substations, or generators are out of service for maintenance or because of forced outages.

The results of the load flow studies allow the engineer to identify which system elements (lines, transformers or circuit breakers for example) will become overloaded under normal (all elements in service, "best case") and during outage conditions. The outage conditions studied include taking each system element out of service (a single contingency) and determining the resulting system voltages and load flows. Additionally, the system is studied with multiple system elements out of service (multiple contingencies, "worst case") which in general will result in a greater loss of system load.

Q. Are the conclusions and recommendations from previous studies relevant?

A. Conclusions and recommendations from prior studies direct the engineer's attention to the issues and solutions that have been identified in the past. These recommendations are reviewed as part of the analysis to determine if the solutions proposed are still viable. Because of changing conditions and requirements, conclusions of previous studies may no longer apply or the year of need specified in a previous study may change. Consequently, the purpose of the study is to evaluate historical information and in combination with current load forecasts, use that to project future system loads and performance under various conditions.

Q. How do the costs of proposed system improvements relate to reliability?

A. Weighing costs against future system performance, which includes reliability, is required on virtually every planning study. A power system that serves large loads, as well as loads that are particularly important to a community's financial well being, warrants a more robust system to avoid the direct economic impact and social disruption that result from power outages. The consequences of an outage of a particular system element, such as a transmission line, transformer, circuit breaker, or combinations of several of these items must be considered in recommending system improvements. For example, the loss of a transmission line serving a 200 MW load would be more important than a distribution line serving 2 MW of load. One can afford to spend more money to make the transmission line more reliable (less susceptible to outages) than for the distribution line. Similarly, the loss of a residential load is not as critical as the loss of a commercial load. One reason is because residential customers can typically defer activities until the power is restored, whereas for commercial customers the opportunity to conduct a transaction is lost, and may never be recovered. In general, higher reliability systems will cost more to construct, and so the more costly improvements must be reserved for instances where critical or larger blocks of load are affected.

DEVELOPMENT AND APPLICATION OF PLANNING CRITERIA

Q. What is the role of planning criteria in the analysis?

A. Planning criteria form the basis for evaluating the performance of the electrical system. The results of the load flow analyses are evaluated, using planning criteria as a guide, to determine whether the system performs acceptably, both under present day conditions and into the future. If the load flow model fails to perform acceptably then alternatives, such as the addition of a new transmission line or a new substation, are developed that will correct the failure. These alternatives are then analyzed as described before. This process is repeated until acceptable alternatives are identified and described, taking into account cost, reliability, and any other pertinent factors.

Q. How has system planning criteria developed?

A. Electrical system planning criteria provide a guide for the development and evaluation of alternatives. Historically, planning criteria have been developed based on successful utility practice, evolving over time along with the growth in size, complexity and importance of electric power systems.

As an example the high voltage electrical network on the mainland grew from isolated systems into the interconnected bulk power system that exists today. With this growth and change came the need to establish planning and operating practices that would result in the economical and reliable operation of the power system. The establishment of realistic planning criteria for the electrical system came about as the result of lessons learned in operating the system.

The North American Electric Reliability Council (NERC) was formed subsequent to the 1965 blackout that affected the northeastern United States and Ontario, Canada, to promote the reliability of the electrical supply in North America.

NERC does this by reviewing the past for lessons learned and, among other activities, creating operating and planning standards. The NERC planning standards and operating policies reflect the combined experience of the utilities in North America. NERC has 9 member reliability councils, such as WECC (Western Electric Coordinating Council), and each of these reliability councils adapts and modifies the NERC guidelines to apply to its own unique system requirements, in some cases more stringent than the NERC guidelines.

Q. What are some examples of lessons learned by utilities?

A. The development of planning criteria is an ongoing process and the criteria are continually subject to review and discussion to address the many issues associated with operation of the high voltage electrical system. Over the past decades, the system has become more "interconnected" and new technologies have been introduced. As a result, the complexity of planning and operating the system has increased dramatically. While the basic planning criteria are well established, the increased complexity of the system combined with the improvements in technology necessitates a continual refinement of the planning process.

The following summary descriptions of electrical system outages and lessons learned are intended to illustrate how past experience has contributed to the development of planning criteria. There are many lessons to be learned from every outage. The lessons learned noted with each description below represent only a fraction of the lessons learned from each outage, and are presented in the context of this discussion regarding planning criteria.

November 9-10, 1965 – Northeast Blackout[1]

A single transmission line from the Niagara Generating Station tripped (opened) which led to other transmission lines tripping and the power system becoming unstable. Once a system becomes unstable, other lines and generators begin opening up in a "cascading" type of failure. The initial tripping was caused by backup relays that were set at thresholds below the actual loads that occurred. The outages affected some 30 million people across an area of 80,000 square miles.

Lessons Learned – The system must be designed to withstand the more probable outages so that the power system remains stable. This particular outage

[1] Consortium of Electric Reliability Technology Solutions Grid of the Future, White Paper on Review of Recent Reliability Issues and System Events, Prepared for the Transmission Reliability Program, Office of Power Technologies, Assistant Secretary for Energy Efficiency and Renewable Energy, USDOE, Prepared by John F Hauler, Jeff E. Dagle, Pacific Northwest National Laboratory, August 30, 1999.

initiated the formation of the North American Electric Reliability Council (NERC) to provide a national forum for review and establishment of standards and guidelines to enhance electrical system reliability.

<u>July 13-14, 1977 - New York City Blackout</u>[2]

A lightning stroke initiated line trips, which, through a complex sequence of events, led to voltage collapse and blackout of the Consolidated Edison system. This outage affected some 9 million people who were without power for some 25 hours. Estimated financial costs were greater than $350 million. Disruption of public transportation and communication was massive and there was widespread looting, arson and violence.

Lessons Learned – Stronger interconnections with neighboring systems are beneficial in maintaining system reliability and stability.

<u>December 14, 1994 – Western States Cascading Outage</u>[3]

Insulator contamination near Borah in southeast Idaho faulted one circuit on a 345kV line importing power from the Jim Bridger power plant in southwestern Wyoming. Another relay erroneously tripped a parallel circuit; bus geometry at Borah forced a trip of the direct 345kV line from Jim Bridger plant. Sustained voltage depression and overloads tripped additional lines. The outage then cascaded through transient instability and protective actions. The load lost as a result of the outage was estimated at 9,336 MW and impacted 1.7 million customers.

Lessons Learned – Multiple contingency events do occur and should be addressed in system planning studies.

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[2] Ibid
[3] Ibid

<u>August 10, 1996 – Western States Outage[4]</u>

Multiple transmission line failures occurred over a period of several hours. The failure of several lines, combined with the day's pattern of operation, caused the system to go unstable. Power was interrupted to about 7.5 million customers, for periods from a few minutes to about nine hours. Immediate cost to the region's economy was estimated at $2 billion. The load lost as a result of the outage was estimated at 30,489 MW.

Lessons learned - Planning and designing for N-1 contingencies is not enough. Rare multiple contingency outages do happen and in some cases the cost of the resultant outage can be unacceptably high, both financially and socially. Multiple contingency outages (outages of more than one system element) must be included in system planning studies.

<u>August 14, 2003 – Northeast/Midwest US Blackout[5]</u>

This outage blacked out large portions of the Midwest and Northeast United States and Ontario, Canada. A sustained outage of up to two days duration was experienced in some areas. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. The blackout, which was massive and is perhaps the largest ever, affected an estimated 50 million customers and 61,800 megawatts of electrical load. Economic loss from the outage has been estimated at $6.4 billion[6]. The outage began in FirstEnergy's system in Ohio and eventually cascaded to effect customers in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and Ontario, Canada. The

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4 Ibid

5 Interim Report: Causes of the August 14th Blackout in the United States and Canada. US-Canada Power system Outage Task Force, November 2003.

6 Northeast Blackout Likely to Reduce US Earnings by $6.4 Billion, Anderson Economic Group, P. Anderson & I. Geckil, AEG Working Paper 2003-2, August 19, 2003.

Interim Report referenced goes into great detail with respect to why and how the outage occurred. In summary, the interconnected mainland electrical power grid has become increasingly complex and is very technically challenging to operate. For example, just prior to the outage, the system was operating reliably within NERC operating policies, and through simulation (load flow) studies it was subsequently determined that the system could at that time continue reliable operations following the occurrence of more than 800 contingencies. The outage began with the trip of the FirstEnergy Eastlake 5 generation plant at 1:31pm. This caused transmission line loadings to increase because of the need to import additional power into the area. Heavier loads caused line conductors to sag and several lines contacted trees and tripped out. Computer failures at FirstEnergy caused system operators to lose situational awareness and as a result corrective actions were delayed and in some cases other interconnected utilities were unaware of the state of the system. Additional events continued to occur and eventually FirstEnergy's system collapsed. Because FirstEnergy's system provided various paths for inter-regional power flows, without those paths the power flowed on alternate paths overloading already heavily loaded transmission lines, which began to trip. At 4:06pm the system began to cascade to a complete blackout.

There are many lessons to be learned from this outage. A few relevant to this discussion include:

1) Rare multiple contingency outages do happen and in some cases the cost of the resultant outage can be unacceptably high, both financially and socially.
2) In addition to studying the more probable single contingency outage scenarios, multiple contingencies (outages of more than one system element) must be included in system planning studies, recognizing that while they may

have a low probability of occurrence they still can and do happen.

3) The interconnected system is extremely complex. Reliable computer systems and real time communications between adjoining system operators are critical to maintain system integrity.

Q. Has the HECO Oahu transmission system experienced outages similar to the outages described as part of the "lessons learned" examples?

A. Yes. On July 13, 1983, a combination of unusual events triggered what ultimately resulted in a system wide blackout on Oahu.

1) Two major 138kV lines were out of service for repairs, one damaged during Hurricane Iwa;
2) A rare three-phase fault occurred on the Kahe-CEIP 138kV line, which was caused by a cane fire and remained on the system for a relatively long time;
3) Relays apparently mis-operated to trip three additional 138kV lines;
4) Key instrument readings were undependable and failed to indicate system conditions accurately to he dispatchers.

The referenced Stone & Webster report[7] goes into great detail regarding this outage. Some of the recommendations from the report that are relevant to this discussion of planning criteria include:

1) The need to consider additional 138kV lines to strengthen the system to withstand multiple contingency outages;
2) Planning should include consideration for minimizing the impacts of "maximum credible outages", which are multiple contingencies that have a low probability of occurrence;
3) Addressing the reliability issue of an outage to the two lines serving Pukele

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[7] This abbreviated information about the blackout is derived from the Stone & Webster Management Consultants report, Hawaiian Electric Company, Investigation of July 13, 1983 Blackout, February 1984.

on a common right of way;

4) Addressing the inability to have one transmission line out of service for an extended period of time.

Lessons Learned –Key lessons learned from this outage are similar to the lessons learned in other areas of the country: outages that have a low probability of occurrence do in fact occur, and should not be minimized in the planning process. Rather, these "less probable" outages must be addressed in planning studies.

Q. What are deterministic planning criteria and how are they used?

A. The NERC Planning Standards[8] describe the fundamental requirements for planning reliable power systems operated at voltages of 100kV or higher. The standards described are deterministic, that is, specific criteria (rules) that govern system performance under various system or component (i.e., line or generator) outage scenarios are set forth. These various criteria, developed through industry experience in operating the electrical system, reflect the more probable forced and maintenance outages that should be evaluated in planning studies, as well as extreme, but less probable scenarios that should also be addressed. As part of the electrical system planning process, an analysis is conducted to determine the response of the system to the various outage scenarios, i.e. one line out for maintenance when another line fails. If the system response meets or exceeds the NERC criteria under prescribed system outage conditions, then the system is in compliance with the standards.

Q. What are the scenarios recommended for study in the NERC Planning Criteria?

A. There are four categories of normal and contingency conditions recommended for study, as summarized in Section I.A, Table I of the NERC Planning Standards.

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[8] NERC Planning Standards, September 1997, and as updated by the NERC Board of Trustees.

Category A – No contingencies. No system components out of service.

Category B – Event resulting in the loss of a single component.

Category C – Event(s) resulting in the loss of two or more (multiple) components.

Category D – Extreme event resulting in two or more (multiple) components removed or cascading out of service.

For each category the utility must decide what scenarios are reasonable to study, as it is not possible to study all possible combinations of outages. This is because if all possible combinations were considered, the sheer number of scenarios would increase to such a degree that one would never finish. This is especially true when studies are completed for Category C and D events.

Q. Are probabilistic methods applied to transmission system planning?

A. To optimize the performance of the electrical system, some entities are beginning to consider the application of probabilistic methods to transmission system planning in order to examine the likelihood of certain possible events and combinations of events based on real world historical outage performance. However, at the present time, a deterministic approach to planning continues to be the primary approach. Needed improvements to the system are determined using approved deterministic planning criteria to identify required system improvements. Subsequent to identification of needed system improvements, it is not uncommon for utilities to prioritize the implementation of a series of projects to accommodate limited financial budgets or operational constraints, based on their perception of the degree of benefits provided by each project.

Q. What would be the approach to considering probabilities for system planning?

A. A probabilistic approach to transmission system planning would include an analysis of system outage data, to augment deterministic standards. Probabilistic studies are much more complex and require substantially more data, time and effort than for a deterministic approach. A probabilistic approach is best applied when there is a large historical database available of detailed outage and failure information covering several decades to provide a basis for the analysis.

Q. Why is a large historical database important?

A. Probabilistic studies are based on known or assumed outage rates, which can be used to compute the probability of an outage occurring to any particular system element or combination of system elements. The number of outage events for a particular facility that can be used in the probability calculations dictates the confidence level of the results. If a substantial amount of data is available, then a higher confidence in the calculated value can be achieved. With little data, probabilities can be calculated, but will not be as meaningful to decision makers, whose responsibility it is to make major financial decisions for a utility.

Q. Why does it take decades to accumulate meaningful data?

A. The goal of ongoing utility planning, design, construction and operating methods is to avoid outages. As a result, outages to transmission level facilities are infrequent and it takes many years to gather multiple data points for a particular geographic area or facility. The outage record of any particular line or facility is affected by numerous factors. For example, the magnitude and frequency of weather events such as high winds, lightning or icing, contamination, maintenance intervals, and geography all affect the outage frequency of the facility. In addition to the frequencies of outages, it is desirable for the data to contain detailed information as to the reason an outage occurred and if possible, information about other events that occurred during the same time period. Because outages are infrequent and the causes of outages vary widely, it takes a very long time to compile a robust database.

Q. Is detailed outage data generally available for transmission systems?

A. That depends on the utility and the records that have been kept. At present, the industry-wide lack of detailed historical outage records for the transmission system makes a primary probabilistic approach problematic. Outage records prior to the last few years, before the wide spread use of computer record keeping, are spotty at best, and many times record only that an outage occurred, and not the duration or cause of the outage. All of these items, occurrence of an outage, duration and cause, are needed to attach meaningful results to the analysis. As time goes on and more detailed records are accumulated for transmission systems, probabilistic methods are likely to take on more significance as a planning and decision making tools for transmission systems.

Q. Are there utility groups that currently employ probabilistic planning methods?

A. The WECC is one entity that has made an allowance for use of transmission line probability based reliability criteria in a very limited way. The WECC Reliability Performance Evaluation Work Group approach is to first apply the NERC deterministic criteria to establish performance requirements and evaluate compliance. Then, in the rare case where it is judged that a facility should meet a criteria classification other than as dictated by the NERC planning standards (Category A, B, C, or D), the Work Group approach is to use probabilistic methods to justify changing the classification of a facility's compliance within the NERC performance categories (given that sufficient outage data is available to conduct the analysis).

It is important to note that this WECC working group process addresses only the requirements relative to changing a facility's performance requirement to a

NERC performance category other than its normal deterministic designation[9], and does not replace the deterministic planning process. One reason that a utility might want to change the category of a particular facility's performance requirement would be to avoid a large financial expenditure to meet the performance standard. For example, an alternative to mitigate the simultaneous outage of two major 500kV lines in the same right of way could be to construct a third line. However, it could conceivably cost several $100 million to permit, design and construct a third line along a geographically separate path. Consistent with the working group approach, it is up to the judgment of each utility in their local area to determine if such an approach is warranted. If the approach is judged warranted, then the utility must perform an analysis for submittal to WECC for consideration of a change in the performance requirement.

Q. Could you summarize your testimony with regard to the development and application of transmission system planning criteria?

A. Transmission system planning criteria have developed over time based on successful utility practice and as a result of lessons learned from major and minor outages. These planning criteria, developed from experience, form the basis for planning and evaluating the performance of the electrical system. As electrical transmission systems grow, new complexities are continually introduced into the planning and operations of the system. As the complexity of the transmission system increases, new problems crop up and the system planning process must respond to these new demands, to assure the continuation of a robust and reliable transmission system. While 100% reliability (no outages) is unattainable, the system must be planned, designed, and operated to withstand foreseeable and

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[9] WECC Reliability Performance Evaluation Work Group, Phase I Probabilistic Based Reliability Criteria Implementation Procedure, Principal Investigator Dr. M.J. Beshir, June 14, 2001.

reasonable contingencies without loss of load, and to provide for overall system integrity during the more extreme and less probable outages. Past outage experience has taught the industry that extreme events do occur, despite everyone's best efforts. Thus, the system must be robust enough to withstand not only the more probable outages, but to also to remain stable during the more extreme and less probable outage scenarios, even if this means some loss of customer load.

Deterministic planning criteria (as opposed to probability based criteria) to evaluate system performance under various contingency scenarios continues to be the basis for the NERC Planning Standards, and is the methodology used by utilities to evaluate and plan system improvements. Use of deterministic criteria is conservative. In most cases this results in a system constructed with a reasonable margin, to allow the system to respond successfully to those less probable outages that can and do occur, and, will occur in the future, despite utility engineers' best efforts.

As time goes on and a large database of transmission line outage data is accumulated, the use of probability based approaches to some aspects of transmission system planning is likely to increase. However, because the complexity of the transmission system will continue to increase as system load grows and new technologies are introduced, the historical databases will always lag the present system configuration and technology. Stated another way, the historical data will represent yesterday's transmission system, rather than the present and future transmission system. The usefulness of probability based approaches is therefore limited to one degree or another because of this, and while the use of probability based planning is likely to increase in the future, the deterministic approach to system planning remains the best method of identifying needed system improvements.

REVIEW OF HECO'S PLANNING CRITERIA

Q. Are you familiar with HECO's 138kV transmission system?

A. Yes. I am very familiar with the Oahu 138kV transmission system. This knowledge has been gained as a result of numerous discussions with HECO staff, and by reading and analyzing various HECO planning studies that relate to the transmission system requirements for the East Oahu area. I have also reviewed the locations and geographical settings of the 138kV transmission lines around the island via helicopter, and by vehicle at various times over the last few years.

Q. Have you reviewed the East Oahu Transmission Project Alternatives Study Update and the East Oahu Transmission Project: Options to the Koolau/Pukele Line Overload Problem, which were finalized by HECO's Planning and Engineering Department in December 2003?

A. Yes. In addition, I provided input on Part 2 of the East Oahu Transmission Project Alternatives Study Update, which addresses the planning process and the application of transmission planning criteria.

Q. Are HECO's planning criteria deterministic?

A. HECO's planning criteria are deterministic and were developed using NERC and other mainland reliability council experience as a guide. The criterion so developed are consistent with NERC Planning Standards and provide general guidelines for all transmission system planning across HECO's system.

Q. How should the HECO Planning Criteria be applied to electrical system studies?

A. The planning criteria are used to evaluate the performance of the electrical system during normal and outage conditions. As with all engineering analysis, engineering judgment must be applied to evaluate the results and recommendations of a particular study. The HECO planning criteria state, "Each case will have to be evaluated from the standpoint of operational experience and engineering design criteria before budgeting." This statement is an acknowledgement that the standards are written to apply to the transmission system generally, and therefore need to be applied with judgment and experience to each specific case.

In the case of the East Oahu Transmission Project Alternatives Study Update, proper application of HECO Planning Criteria is very important. Central to this study is the requirement to maintain electric service to the Kamoku-Pukele and Downtown service areas with one line out for service for maintenance, followed by an outage of a second line.

Q. Do you agree with the conclusions in the study regarding the need for and objectives of the East Oahu Transmission Project?

A. Yes. I agree that the application of HECO's transmission planning criteria, and prudent transmission planning judgment, fully support the need to address the transmission reliability problems and concerns identified in the study update.

Q. An important objective of the East Oahu Transmission Project is to improve the reliability of the Pukele substation, which receives power from two 138 kV transmission lines. Do HECO's transmission planning criteria require that all substations be served by three 138 kV transmission lines, so that no customers lose service if a line trips out of service while another line is out of service for maintenance?

A. No. Section IV.3 of HECO's transmission planning criteria requires that with any transmission line out of service for maintenance and then a second line fails unexpectedly, no transmission component will exceed its emergency rating. The criteria goes on to say that the purpose of this criterion is to help assure that the system will survive and that all loads may not continue to be served.

HECO's planning criteria do not require that it be able to maintain service to all customers in the event of this type of double contingency transmission line outage; HECO recognizes that it may be necessary to drop customers in order to prevent catastrophic system failure under certain emergency conditions.

As a result, the criteria recognize that it may be acceptable, in some instances, for some customers to temporarily incur outages when two transmission lines are out of service. In other words, it may be acceptable to have substations receiving power from only two 138kV lines, where customers receiving primary service through that substation will incur outages when both lines are out of service (if they do not receive alternate service through another substation during the outage).

Q. Does that somehow invalidate HECO's concern about improving the reliability of its Pukele substation?

A. Absolutely not. Transmission planning criteria, including HECO's criteria, generally establish minimum guidelines, not maximum requirements. While it is not practical, and therefore not standard practice, for transmission planning criteria to address all double contingencies, it is good engineering and operating practice (i.e., prudent transmission planning practice) to plan and design utility systems to withstand double contingencies without loss of customer load, where important customer loads are involved, and double contingencies are reasonably foreseeable.

Thus, the statement in the HECO criteria that "all loads may not continue to be served" is not intended to imply that failing to serve the electrically large and important Downtown core business district and the Waikiki tourism based loads is an acceptable outcome should a transmission line fail while another line is out for maintenance. By way of contrast, the loss of a smaller amount of primarily residential load may be an acceptable outcome based upon the relative impact of the outages. In this way the planning process can allow experience and judgment to be applied to the system planning process to treat the various load centers with consideration as to size, importance and other factors.

Q. Please explain what is meant by a double contingency outage of two transmission lines.

A. This can occur on a power system as a result of <u>unscheduled</u> or <u>scheduled</u> outages. For example, if a system disturbance occurs under normal conditions with all lines in service, and an unexpected (unscheduled) event causes the loss of two lines, this is a double contingency outage and systems are not normally planned for this type of event. If one line is out of service for maintenance, a scheduled outage, and a second line is lost due to an unscheduled outage, this situation is still characterized as a double contingency outage. However, in the second instance, with one line out for maintenance, systems are planned to cope with this situation both with and without loss of load.

Q. Are the HECO planning criteria as stringent as NERC Planning Standards with respect to double contingencies?

A. The HECO criteria are actually less demanding than the NERC criteria. NERC Standard S2.[10] reads as follows:

> "The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as

[10] NERC Revised Phase I Planning Standards, June 12, 2001, page 5.

> defined in Category B of Table I".
>
> "The transmission systems also shall be capable of accommodating planned bulk electric equipment maintenance outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category B of Table I."

The contingencies defined in Category B of Table I include the situation where one line is already out of service when a second line is lost unexpectedly. Whether or not a loss of load is acceptable under a double contingency situation with one line out for maintenance depends in large degree on the criticality of the loads being served, and the details of the particular situation. The NERC Planning Standards address this as well:

> "The regions, subregions, power pools, and their respective members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the Planning Standards and which reflect the diversity of individual electric system characteristics, geography, and demographics for their areas."[11]

Thus, the NERC Planning Standards require that important loads continue to be served with a single line outage occurring when one line is out for maintenance[12], whereas the HECO criteria do not require that all loads continue to be served for this contingency. At the same time, planning criteria generally are intended to set minimum guidelines, rather than maximum requirements, and reliability concerns not explicitly addressed by the criteria can and should be considered by HECO's transmission system planners. This is particularly important in the case of HECO,

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[11] NERC Planning Standards, September 1997, page 4.

[12] The NERC Planning Standards allow some loss of load under these conditions, specifically to radial customers or some local network customers supplied by the faulted component if the loss of load does not adversely impact the overall security of the system. Ibid see Table I, page 13-14, footnote b. In the context of the overall system, the loads allowed to be lost would not be major system loads.

which is not interconnected to other systems.

Mainland utility systems are designed based on providing system reliability, with dependence on neighboring systems as a fundamental part of the stratagem, in order to develop a reliable power system at the lowest overall cost. For example, the NERC Planning Standards state:

> "The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations." [13]

Since there are no "neighboring systems" on Oahu, it makes sense that HECO's criteria may not be as strict as those on the Mainland, but that HECO needs to be conservative and take care in the application of its criteria.

Q. Please explain your statement that HECO's transmission planning criteria generally set minimum guidelines, rather than maximum requirements.

A. As stated in the first sentence of the HECO criteria, "The purpose of these criteria is to establish *guidelines* for planning a reliable transmission system for the island of Oahu." [emphasis added]. These guidelines are minimum requirements, not design standards. The fact that this is a guideline for the system does not preclude the use of a more conservative criterion for a particular situation, such as at Pukele, where a reasonable or foreseeable contingency could result in an unacceptable loss of load. The issue with respect to the criteria in this case is whether or not a loss of load is acceptable or not, in the situation where one line is out for maintenance and the other line is lost. 100% service reliability is not attainable, however, it is the utilities' responsibility to use their best judgment and planning expertise to build a system that responds to various system requirements, including reliability, load

[13] Ibid, Guide G1, page 11.

growth, load distribution, and service to critical loads.

Q. Is HECO proposing a double contingency criterion as "standard practice"?

A. HECO is not proposing to construct the system to withstand all double contingency outages, but only in those instances that in its judgment, and after detailed study, warrant that level of construction. While it is appropriate that a wide range of scenarios be evaluated in the system planning process, it is also appropriate that local conditions be factored into the conclusions drawn from the analysis. In this way, the resulting plans will be responsive to system, cost, and local needs.

Q. If it is not standard practice under either the NERC Planning Standards or the HECO transmission planning criteria to design a system to meet all double contingencies, when should a system be designed and planned to withstand such contingencies.

A. As stated above, where important loads are involved, systems can and should be planned and designed to meet a double contingency criterion. These special situations must be evaluated in light of local conditions, and customer and system requirements. It is the utilities' responsibility (in this case HECO) to analyze the situation and make appropriate judgments as to what is appropriate. For example, the NERC Planning Standards state:

> "The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network."[14]

It is the system planners' responsibility to study the system in detail, and based on sound engineering judgment, identify the best and most cost effective system configuration for each situation. Whether a particular contingency is "reasonable"

[14] Ibid, Guide G3, page 12.

or "foreseeable" or a loss of load is "unacceptable" is a matter of judgment and familiarity with the details of a particular situation.

Q. How does this apply to HECO's Pukele substation reliability concern?

A. In this case, HECO has proposed the project, in part, because of the importance of the Waikiki load and the fact that the Pukele substation is the most heavily loaded substation on Oahu. The importance of the loads served by the Pukele substation and the negative effects that could result from a Pukele substation outage are discussed in Ms. Ishikawa's testimony, HECO T-4.

The Pukele substation serves a large portion of the Oahu load (approximately 16%), including the important Waikiki commercial and hotel loads, as well as the residential and commercial loads inland. The two 138 kV lines feeding the Pukele substation are more than 40 years old, and maintenance activities on these lines take more time and are more difficult than for 138 kV lines along City and State roadways in town, due to the limited and sometimes hazardous access to the Koolau Mountains. The lines are also exposed to higher winds and corrosive weather in the mountains. The very difficult access to the lines as they cross the Koolau Mountains, their exposure to corrosive marine air, and the location of the two lines on a common right of way, cause these lines to be at a relatively higher risk than the transmission lines in other areas of the island.

The project will increase the reliability of the electrical power supply to the Waikiki service area by eliminating power outages resulting from the loss of both of the existing lines feeding the Pukele substation when one of the lines is out of service for maintenance.

Q. Could you summarize your testimony with regard to your review of HECO's transmission system planning criteria and the East Oahu Transmission Project?

A. HECO's transmission system planning criteria are reasonable and prudent, and are based on the NERC Planning Standards. HECO's planning standards are not design standards, but are guidelines for planning and operating the transmission system. HECO's planning standards form the basis for the conduct of electrical system planning studies and for the construction of new transmission system additions. As stated in the criteria "Each case will have to be evaluated from the standpoint of operational experience and engineering design criteria before budgeting." This statement is an acknowledgement that the standards are written to apply to the transmission system generally, and therefore need to be applied with judgment and experience to each specific case.

As applied across the system, HECO's planning criteria do not require all loads to be served in the case of a double contingency outage: For example, where one line is out for maintenance and a second line fails. However this is not intended to imply that failing to serve the electrically large and important Downtown core business district and the Waikiki tourism based loads is an acceptable outcome should a transmission line fail while another line is out for maintenance. The system planning process must account for times when lines are out of service for maintenance. In addition to applying the basic planning criteria, common sense, judgement, and experience must be applied to determine what loads are important, and which loads are less important in each contingency scenario evaluated.

It must be emphasized that the Pukele Substation service area:

1. comprises a large portion of the island load;
2. includes the economically important Waikiki area;
3. is served via two 138kV lines on a common right of way; and
4. the two 138kVlines traverse the difficult to access and weather

challenged Koolau Mountains.

Consequently, it is important that HECO take action to increase the reliability of the system serving the Pukele Substation.

Q. You have discussed the need to improve the reliability of the transmission system serving the Pukele Substation. Are there other system concerns in East Oahu that should be addressed?

A. Yes. In addition to the Pukele reliability concern, there are several other important system concerns in East Oahu, including:

1) The Koolau/Pukele Line Overload
2) Downtown line Overload
3) Downtown Substation Reliability

A complete planning process for East Oahu must address these concerns in addition to the Pukele Substation reliability issue. Planning studies must apply the approved planning criteria and identify all of the problems and issues in the area of study that occur within the planning horizon. The East Oahu studies must identify and evaluate alternatives for solving the identified problems. Please refer to Ms. Ishikawa's testimony (HECO T-4). In her testimony, Ms. Ishikawa explains all four of these problems, provides background information and data for the East Oahu Transmission Project studies, and describes the proposed alternative and recommended solutions.

Q. Does this conclude your testimony?

A. Yes, it does.